Contract No. **DTRS56-95-C-0003**

RSPA-97-2095-1

TEXAS TRANSPORTATION INSTITUTE

Engineering Support Services for the Office of Pipeline Safety-Task 1

TEXAS TRANSPORTATION INSTITUTE
THE TEXAS A&M UNIVERSITY SYSTEM
COLLEGE STATION, TEXAS

in cooperation with the
U.S. Department of Transportation
Research and Special Programs Administration
Office of Pipeline Safety

Engineering Support Services
for the Office of Pipeline Safety
(Task 1)

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Research and Special Programs Administration
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Contract No. DTRS56-95-C-0003

Texas Transportation Institute
The Texas A&M University System
College Station, TX 77843-3 135

Technical Report Documentation Page

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.
Task 1		

4. Title and Subtitle	5. Report Date
ENGINEERING SUPPORT SERVICES FOR THE OFFICE OF PIPELINE SAFETY (TASK 1)	July 1997
	6. Performing Organization Code
7. Author(s)	8. Performing Organization Report No.
Daulat D. Mamora, Frank M. Platt, and Arthur H. Reine	Task 1
9. Performing Organization Name and Address	10. Work Unit No. (TRAIS)
Texas Transportation Institute The Texas A&M University System College Station, Texas 77843-3135	11. Contract or Grant No. Contract No. DTRS56-C-0003
12. Sponsoring Agency Name and Address	13. Type of Report and Period Covered
COTR: U.S. Department of Transportation Research and Special Programs Administration Office of Pipeline Safety (DPS-13) 400 Seventh Street, SW, Room 2335 Washington, DC 20590-0001 Attn. Mr. Gopala Vinjamuri	Final: June 1995 to April 1997 14. Sponsoring Agency Code

15. Supplementary Notes

Research performed in cooperation with the U.S. Department of Transportation, Research and Special Programs Administration, Office of Pipeline Safety.

Research Study Title: Review and Recommendations for Standards for the Design, Construction, Operation, and Maintenance of Breakout Tanks

16. Abstract

Currently, the U.S. Department of Transportation (DOT) has few standards in 49CFR Part 195 for aboveground pipeline breakout tanks. The objective of Task 1 was to develop recommendations for the design, construction, and maintenance of breakout tanks and secondary containment. To attain this objective, the following tasks were carried out.

First, an analysis of existing standards for breakout tanks was conducted, including API Standards and Recommended Practices, STD 620, 650, 653, 2000, 2015, 2610, and RP 651, 652, 2003, 2350, and ANSI/NFPA 30.

Second, a total of 411 breakout tanks were visited. The tanks were located in six states, geographically spread out across the lower 48 states. During the site visits, researchers held discussions with operators on the design, construction, operation, and maintenance of breakout tanks. The discussions included operational and maintenance problems and their resolution related to industry standards for breakout tanks.

Third, based on analysis of existing industry standards and observations from the site visits, recommendations were developed for the adoption of certain industry standards for breakout tanks.

The main recommendation of this study is that 10 API publications and one NFPA Code be. adopted by DOT for the design, construction, and maintenance of breakout tanks.

17. Key Words	18. Distribution Statement
Pipeline Tanks, Breakout Tanks, API Standards	No restrictions.

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price
Unclassified	Unclassified	52	

Form DOT F 1700.7 (8-72) Reproduction of completed page authorized

ENGINEERING SUPPORT SERVICES FOR THE OFFICE OF PIPELINE SAFETY- (TASK 1)

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Research Report Number: Task 1

Research Study Number: DTRS56-95-C-0003

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Sponsored by the

U. S. Department of Transportation

Office of Pipeline Safety

July 1997

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IMPLEMENTATION STATEMENT

It is recommended that the U.S. Department of Transportation adopt the relevant API Standards and Recommended Practices and ANSI/NFPA 30 as Federal Code for the design, construction, operation, and maintenance of aboveground breakout tanks and secondary containment structures.

The study found the API Standards and Recommended Practices as well as ANSI/NFPA 30 are applicable for breakout tanks and are used by industry. These guidelines have played a major role in creating a very low rate of accidents for breakout tanks.

DISCLAIMER

The contents of this report reflect the views of the authors who are responsible for their acts and the accuracy of the data presented herein. The contents do not necessarily reflect the official view or policies of the Department of Transportation. This report does not constitute a standard, specification, or regulation, nor is it intended for construction, bidding, or permit purposes, The engineer in charge of the project was Dr. Daulat D. Mamora.

ACKNOWLEDGMENT

The authors of this study wish to thank Ms. Marty Matheson of API for all of her help in facilitating access to reports, data and introduction to the API Pipeline Operations Committee.

The authors are indebted to the pipeline operators who made possible the site visits to complete this study.

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SUMMARY

Under 49CFR Part 195, the U.S. Department of Transportation’s Office of Pipeline Safety (OPS) is responsible for the safety of the hazardous’ liquid and carbon dioxide pipelines, including aboveground breakout’ tanks, in the United States. This study was commissioned to develop recommendations for the adoption of industry standards for the design, construction, maintenance and operation of breakout tanks and containment structures.

This study involved a review of Standards and Recommended Practices written by the American Petroleum Institute (API) as well as other relevant industry standards. In addition, site visits were conducted to 411 breakout tanks at 16 pipeline terminals in six states. These tanks contained 47 million barrels of storage. Based on the literature review and site visits, conclusions as to appropriate industry standards and recommendations for their use in the Federal Pipeline Safety Regulations were made.

During the site visits, researchers found all of the operators have either completed or begun implementation of API STD 653 for maintenance inspection of breakout tanks. Spills of hazardous liquids from breakout tanks have declined dramatically since implementation. For a lo-year period (1977-1986), accident rates were approximately 0.1% of the inventory annually, and since implementation of the first edition (Jan. 1991) of API STD 653, this low accident rate figure appears to remain very small.

Based on this study, it is recommended that OPS adopt 10 API Standards and Recommended Practices as well as ANSI/NFPA 30 to supplement the Federal standards for breakout tanks and secondary containment.

1 Hazardous liquids are defined in Section 195.2 as petroleum, petroleum products, or anhydrous ammonia.

2 Breakout tanks are defined in Section 195.2 as a rank used to (a) relieve surges in a hazardous liquid pipeline system. or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

I. OBJECTIVES OF TASK 1

This report describes the work undertaken to meet requirements for Task 1 of the Project awarded to the Texas Transportation Institute (TTI) by the Office of Pipeline Safety (OPS). The requirements for Task 1 have been defined by OPS as follows:

Task 1 *was* to *develop recommendations for standards for the design, construction, operation, and maintenance of aboveground pipeline tanks for the storage of hazardous liquids and secondary containment structures. The recommendations will give special attention to standards for tanks that are an integral part of a pipeline facility.*

To meet the objective of Task 1, the following approach was taken. First a review was conducted of the existing standards and recommended practices that have been written by the American Petroleum Institute (API) and other industry associations. These included API Standards (STD) 620, 650, 6.53, 2000, 201.5 and 2610; API Recommended Practices (RP) 651, 652, 2003 and 2350; and ANSI/NFPA-30. Second, following this review, onsite visits to petroleum pipeline terminals were-made with an initial limit of seven to nine visits which was later increased to 16. The visits included operators in the lower 48 states with pipeline terminals throughout the United States. Third, based on the literature review and site visits, recommendations were developed for aboveground storage tank standards to be adopted into 49 CFR Part 195.

II. SITE VISIT SELECTION

A. Criteria for Site Selection

Site visits were made to determine the standards and practices used by the hazardous liquid pipeline industry in the operation of their breakout tankage facilities. The number of sites and their geographic locations allowed for both regional and company-by-company variation in standards and practices. For site selection, specific questions to be answered were as follows:

1. What tanks are covered under the requirements for Task 1?
2. Which operators should be visited?
3. What areas of the country should be visited?
4. Should any specific area require additional sites due to location or special conditions?

The type of tank visited was defined by OPS. OPS stated that this study could only include aboveground breakout tanks. A breakout tank is defined under Federal Code 49 CFR Part 195.2 as being "a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for re-injection and continued transportation by pipeline."

Two methods were considered for selection of operators for site visits. The first and optimum method was a random selection from the available inventory of breakout tanks. A second method was to contact a list of operators and ask for potential sites. Random selection was the initial method chosen for this task. For random selection, a potential inventory of tanks was found in a report prepared for API by Entropy Limited of Lincoln, Massachusetts, dated 1989. Entropy's report was an estimated inventory of all aboveground tankage in the United States. The report estimated that there were 9,197 tanks[1] in the transportation sector of the petroleum industry. Since the transportation sector consists of pipeline tanks[2], and the majority of these

1 8.107 on interstate and 1.090 on intrastate pipelines

2 excludes natural gas liquids

tanks are assumed to meet the definition of a breakout tank, they would normally have been used for the study. In any event, all these aboveground liquid storage tanks are designed, constructed, and maintained in accordance with the same standards and practices.

API gave us permission to use the data in the Entropy survey. The data, however, is in the physical possession of Entropy. Texas Transportation Institute and API made multiple unsuccessful attempts to contact Entropy and obtain the data. Consequently, the random method for selection of operators to be visited was abandoned in favor of the second method.

The second method was implemented with the assistance of API. API supplied a list of the operators who were members of their pipeline committee. Members of the committee were contacted and most supplied several potential sites. All of the sites visited were selected by TTI from this list. The operators on the list either own or operate the majority of the hazardous liquid pipelines in the United States, and their list provided a wide geographical sampling of the United States.

B. Geographic Areas Visited

The original requirement for site visits called for seven to nine sites with multiple operators. This requirement was later increased by OPS to 15-20 sites over the contiguous 48 states. The list was eventually reduced to a final 16 sites in six states. Locations varied from New Jersey to California (East-West) and Texas to Wisconsin (North-South). Figure 1 is a map with the 16 sites highlighted. A chronological list of the sites is shown in Table 1. This table contains the number of operators visited at each city, the number of breakout tanks, total volume, type of product, and the average age of the tanks. Table 2 gives the average rainfall and temperature range for each site location, and also shows the range of climatic operating conditions for the sites visited. These conditions include variations from light to monsoon rain patterns, desert to semi-arctic. and included areas with environmental concerns such as earthquakes and population sensitive to environmental issues.

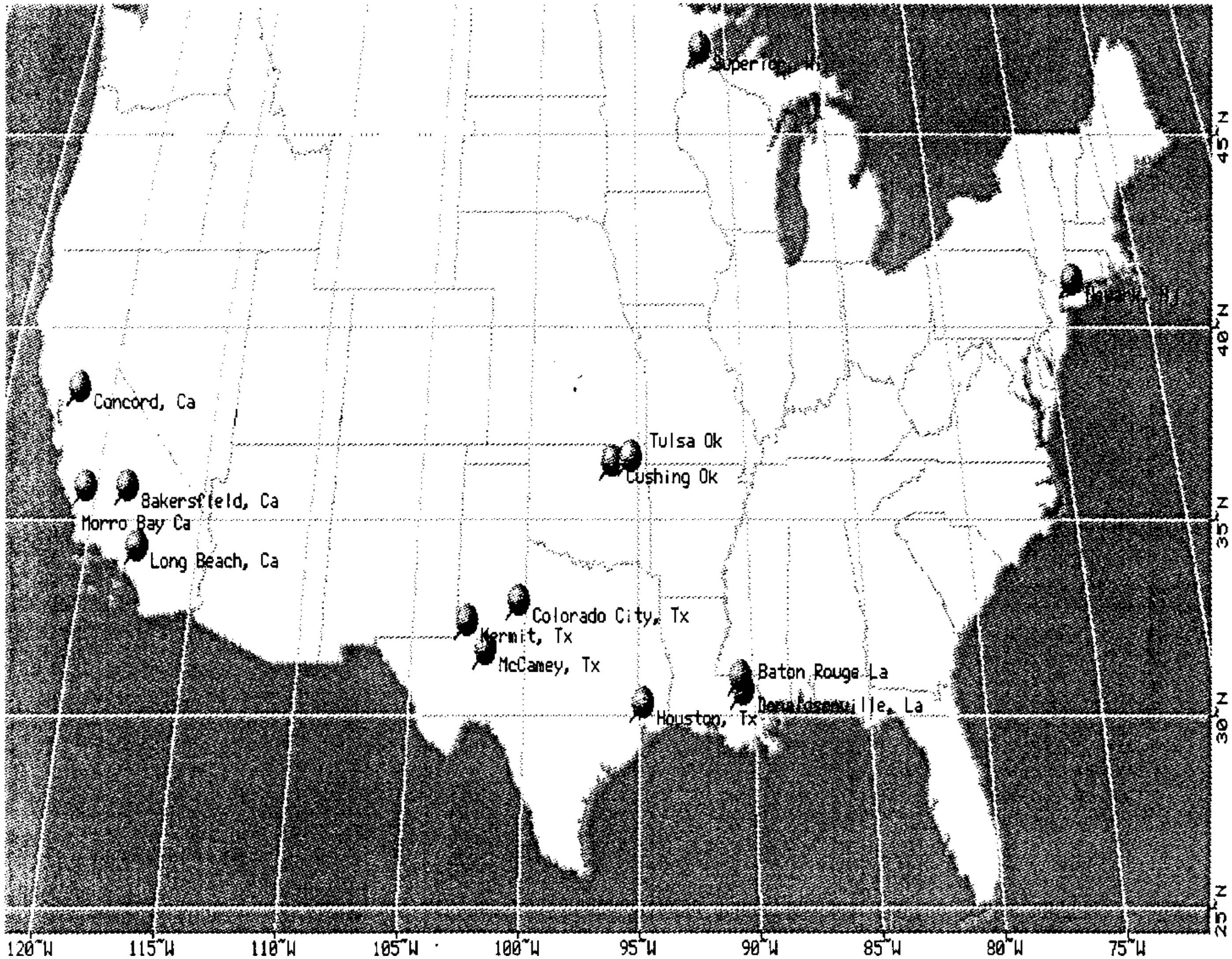

Figure 1. Map of Sites Visited

Table 1. Chronological List of Sites Visited

City	State	Number of operators	Number of tanks	Shell volume (MMB)	Product type*	Average age, (yr.)
Colorado City	Texas	1	17	2.3488	Crude	42
McCamey	Texas	1	31	2.632	Crude	57
Kermit	Texas	1	28	1.086	Crude	43
Houston	Texas	2	40	4.4108	Mixed	40
Tulsa	Oklahoma	1	30	1.8733	Mixed	36
Cushing	Oklahoma	2	115	12.502	Crude	68
Newark	New Jersey	1	25	2.957	Refined	4
Bakersfield	California	1	11	0.598	Crude	60
Long Beach	California	1	16	1.5438	Refined	~20
Morro Bay	California	1	23	2.127	Crude	61
Concorde	California	1	23	1.188	Refined	-25
Superior	Wisconsin	1	27	5.430	Mixed	33
Baton Rouge	Louisiana	1	23	2.518	Mixed	18
Donaldsonville	Louisiana	1	20	6.080	Crude	25
Total		16	411	41.398		45

* Mixed - Includes all types of fluids such as crude oils and refined hydrocarbons.

Refined Includes gasoline, diesel. fuel oil, jet fuel and kerosene.

Crude Includes all types of crude oils, from heavy California crude oil to gas condensates.

MMB - Million barrels (42 gal barrel).

Table 2. Sites Visited and Annual Weather Data

City	State	Average High Temperature °F	Average Low Temperature °F	Average Precipitation, inches
Colorado City*	Texas	95.2	24.7	14.96
McCamey*	Texas	97.6	35.4	17.29
Kermit*	Texas	95.2	35.4	14.96
Houston	Texas	93.8	37.8	50.59
Tulsa	Oklahoma	95.8	20.3	40.6
Cushing*	Oklahoma	95.8	20.3	40.6
Newark	New Jersey	87	23.4	43.97
Bakersfield	California	109	34	5.72
Long Beach	California	103	34	11.8
Morro Bay	California	93	31	15.73
Concorde*	California	106	28	19.01
Superior	Wisconsin	77.5	10	28.91
Baton Rouge	Louisiana	92.3	35.4	60.89
Donaldsonville*	Louisiana	92.3	35.4	60.89

* Data for these sites collected from nearest reporting station.

The temperatures are the average Summer and Winter highs.

All data collected from the National Climate Centers.

Sites are listed in the chronological order visited.

This list of potential sites generated from the industry list was submitted to OPS for approval. The list submitted became the final list with one modification The modification was the addition of Wisconsin to the list. This site includes the most severe winter conditions that are usually seen in the contiguous 48 states. When possible, multiple operators were found in each geographic area in order to reduce travel cost. This allowed us to see more sites in more areas.

III. SITE VISITS

A. Design and Construction

The majority of breakout tanks were built before 1950. All of the tanks built before 1936 were riveted, and generally those built later were welded. The tank builders consisted primarily of four companies. The company used for design and construction of the majority of tanks was Chicago Bridge and Iron. All of the tanks visited were built under the following standards. The riveted tanks were built using API 12A which was the standard in the period 1928-1941. Large bolted tanks used API 12B. Welded tanks used API 12C for tanks built between 1936 and 1961, and API STD 650 for tanks built after 196 1.

Foundations of the tanks varied, ranging from ring walls to bare soil. The general condition and appearance of the inventory visited was excellent. Several of the tanks had been degassed, cleaned, and were in the process of overhaul or rebuild.

B. Cathodic Protection

All of the operators visited, use some sort of cathodic protection at the majority of their facilities. The primary method of cathodic protection was provided by rectifiers (impressed current systems), although at some sites sacrificial anodes were used. Generally, cathodic protection is the recommended method of reducing corrosion to the tank bottoms. Local conditions, however, can affect the outcome of any method used.

However, some tanks visited did not have cathodic protection. One operator has three terminal facilities in the same area and only one was cathodically protected. The non-protected tanks tended to have less corrosion than the tanks that had been protected. This reduced level of corrosion could have been caused by the low moisture content in the soil. The increased corrosion found at the protected site could have been caused by faulty construction practices when the facility was built. such as mishandling the plates and damaging the coating before placement. The unprotected facilities were built in 1919, and the protected facility was built in the 1970's.

Most of the operators are in the process of installing half-cells to measure the electrical potential in the center of the tank. The half-cell placement uses an X pattern under the tank, using either horizontal holes bored under the tank bottom or by trenching and burying the half-cell when replacing the tank bottom. Of the two, if the tank bottom does not need replacing, the boring method appears to be less costly and is as effective as the trenching method.

A question arose concerning the grounding of the tanks. Some operators were concerned with the effect tank grounding had on cathodic protection. During discussion with the operators, their conclusion was that tank grounding drained the current from the rectifier circuit. Consequently, some of these operators have removed the direct ground to the shell. The external floating roof was grounded by connection to the ladder which was free-standing or was separately grounded. For operators who have removed direct grounding to the shell, secondary grounding of the shell is obtained either through direct contact between the tank bottom and soil, or through the metallic straps (bonding shunts) to the roof seal wipers and the ladder.

C. Tank Bottoms

Most of the older tanks visited have either had the bottoms replaced or repaired since construction. After repair, most of the bottoms were coated or lined with an epoxy-based or glass-reinforced concrete, gunnite, or other “impermeable” material. These materials can prevent internal corrosion of the bottom. The applications and choice of material varied from site to site. The best results appear to be from the use of epoxy-based or glass-reinforced linings.

D. Painting

External painting is not specifically covered under the referenced API standards. The operators, with one exception, had all of their shells painted. The painting of the shells has three purposes.

The first is aesthetics; it tends to give the appearance of a high level of operator maintenance. This tends to raise the opinion of the company held by the general population. Second, it can reduce corrosion due to weather. Third, by selecting light reflective colors, painting the shell and roof reduces the temperature gain of the tank contents due to the sun. Moderating the temperature gain of the stored liquid reduces the liquid lost to evaporation and emission that contribute to air pollution.

One operator painted only the top ring of the internal floating roof tank and the cone roof. The facility was in an area where weather was not a factor in corrosion of the exterior. The facility was not near a population center which might influence the decision. All of these tanks were riveted, and built prior to 1920. Most had some incidental seepage which tended to blend with the bare metal finish. The tank shells appeared to still have the original mill finished steel. It should be noted that the requirement in 49CFR 195.236, “External corrosion protection.” does not apply to breakout tanks constructed prior to April 1, 1970.

E. Corrosion

Corrosion problems encountered were primarily in the tank bottoms. All of the tanks, when degassed, are inspected using the guidelines specified in API STD 653. During these inspections, the tank bottoms are generally inspected using either Magnetic Flux Exclusion (MFE) or Ultrasonic (UT) techniques, and the tank shells by ultrasonic methods. The number and frequency of test points varies from operator to operator, but upon detection of significant metal loss, the location is replaced. For significant corrosion of tank floor, additional mass is added by over-plating. Excessive corrosion in the shell requires replacement. After inspection of the interior floor sections, some of the operators coat the bottom with an impermeable lining.

F. Secondary Containment

For aboveground breakout tanks. 49CFR 195.264 requires that a means must be provided for containing hazardous liquids in the event of spillage or tank failure. The containment structure is usually an earthen dike. Under NFPA-30, the containment structure must contain the volume of the largest enclosed tank plus volume occupied by other tank shells (below the height of the dike) that are within the same containment structure. The wall of the enclosure must have access for equipment and personnel to enter and allow for fire fighting, if necessary. All of the operators were complying with constraints of this standard. The standard provides considerable operator latitude. One operator, to meet this standard, built a 2-3 foot earthen berm around the perimeter of the entire facility. If a tank were to fail, contamination of the entire facility could occur. A second facility, built on hilltops, channels any spills to ponds located at the end of a small valley approximately 500-700 yards from the tank. These facilities meet the NFPA-30 standard for remote impounding, but in the event of a failure, might cause an environmental problem. An example of the optimum design was a site that enclosed each tank within an individual berm. Any failure of a single tank would not have an effect on the other tanks on the site. One facility located within a builtup area used several containment structures composed of both earth and concrete to enclose the tanks. Although any tank enclosed with other tanks would stand a greater chance of failure due to a fire at an adjacent tank, this design does not violate NFPA-30.

G. Groundwater Monitoring

The monitoring of groundwater is presently covered under the API standards. Several of the sites were under local or state regulation concerning monitoring of collected rain water in the berm. Contaminated water would be disposed of in the proper manner. Of the sites visited, only three have had groundwater monitoring installed. However, none had an ongoing monitoring program to detect problems. One site, however, has installed some leak detection devices on valve installations to detect leaking seals and prevent contamination of groundwater.

H. Maintenance, Inspection and Safety Practices

All of the facilities have maintenance and inspection programs. All operators have begun to implement programs that follow the guidelines outlined in API STD 653. Each operator has tailored a program of safety practice to fit their facilities and budget. Within these programs are lockout/tagout, cleaning, testing of atmosphere, entry, and closed space work requirements. These safety practices appear to be very close to those outlined in API STD 2015 but do allow some latitude for certain requirements pertaining to each facility.

I. Roof Types

Roof types varied between operators. The majority of the tanks were external floaters with the exception of a large operator in Oklahoma. All of the roofs were undergoing periodic maintenance and modification. Several operators were replacing external floating roofs with geodesic domes and internal floating roofs. Of the two operators who have installed domes, one was extremely pleased, and the second was hesitant to state his opinion. All of the external floating roofs appeared to have adequate drainage for the removal of rain water. Several operators were retrofitting the drains with a coflexit type of hose. This steel hose appears to be superior to the previous (rubber) type of hose.

J. Tank Product Composition

The majority of tanks visited contained crude oils. The crude oils varied from gas distillates to low gravity crude oils from California. Several operators, however, had facilities that contained a wide range of refined products. These included diesel, gasoline, jet A, heating oil, kerosene, and the new California blend of oxygenated gasoline. Factors that may affect the operation of the facilities and their tankage are composition of stored liquid and temperature. The variables in composition that affect operations are sulfur content, API gravity, and viscosity. The second factor, temperature, also has a direct effect on operation. This factor can affect operations due to the relationship temperature has with viscosity and vapor pressure. If the temperature increases, the viscosity will decrease, and also the vapor pressure produced will increase.

As an example, one operator insulated all tanks at a facility to retain heat. If the temperature of the crude were to drop significantly, the increase in viscosity would either increase the horsepower required to move the crude or reduce the flow rate in the pipeline. An increase in temperature during storage, pumping, or transport within the pipeline could increase the amount of vapor produced. One operator spent several million dollars at one facility to install vapor collection and disposal systems for the storage tanks. The amount of product loss due to vaporization reduces the profitability of the facility. Additionally, evaporation losses through any gaps in inadequately fitted peripheral seals may contribute to air pollution.

K. Fire Protection

Of the facilities visited, all had some type of permanent fire protection. Some of the crude facilities have water mains and fire hydrants. The refined product facilities are generally better equipped because of the volatility of the stored products. The refined product facilities are generally protected by foam systems. In some cases, where the facility was in a built up industrial area, the location of the foam generators and pumping facilities appear extremely confined. In one site, if multiple tanks are involved, tire fighting could be compromised due to the inability to reach the foam generators.

Special attention should be given to operations with local governmental agencies. In the event that a facility has a major spill or fire, the local authorities in charge, should make optimum use of all parties familiar with the site. Failure to optimize the assets available at the site may cause a greater loss than if they were used correctly. The operator may have special personnel or equipment that is unavailable to the local agency. All facilities should have a pro-active plan, as required by 49CFR Part 195.402, "Procedural manual for operations, maintenance and emergencies." that can be well documented and practiced.

One site on the Texas Gulf coast is host to a Texas A&M University class each year to practice and simulate disasters. During their simulation, local agencies are asked to participate at some level. Without planning and practice, events can overtake both the operator and the local agency onsite.

The lack of this type of preparation has occurred in the past. Tanks have caught on fire or failed and the local agency, usually the tire department, responds to the site. In one case the local tire department would not allow the local facility personnel or the operator's own experts to assist. This wastes time, product, and assets. The operator, through their own procedures, may be able to reduce the duration of the tire by pumping out the product while the tank is on fire. This can reduce environmental damage as well as capital loss to the operator.

IV. REVIEW OF API STANDARDS AND RECOMMENDED PRACTICES

A. Summary

The API Standards and Recommended Practices were written by industry professionals and produced by The American Petroleum Institute (API), an organization created and supported by industry. The publications sold by API are well written, practical, and are excellent reference materials. The API publishes an annual reference catalog, "Publications, Programs and Services Catalog".

Based on our review of the API publications, together with site observations and discussions with operators, it is recommended that OPS adopt 10 API Standards and Recommended Practices and ANSI/NFPA-30 to supplement Federal standards for aboveground breakout tanks. These Standards and Recommended Practices have been developed by industry experts over a long period of time. However, as required by Task 1, we have reviewed and made comments on and suggestions for improvements to these Standards and Recommended Practices. We wish to stress that our comments and suggestions - as described in the following - are preliminary only and serve to highlight areas that appeared to us to merit further review. OPS may wish to review these suggestions in the future.

I. *STD 620 Design and Construction of Large, Welded, Low-Pressure Storage Tanks, Ninth Edition. February 1996 (incl. Addendum of December 1996)*

This standard covers the design and construction of large welded low-pressure aboveground tanks. These tanks are designed to contain the vapor above the liquid at pressures not exceeding 15 psig and a temperature not exceeding 250°F. API STD 620, like all of the API standards, is extremely well referenced. Based on the tanks surveyed in this study, its applicability is questionable. None of the 411 tanks (47 million barrel shell capacity) visited for this project were constructed under this standard. However, tanks built to this standard are occasionally found in pipeline terminals and some are known to be in breakout tank service.

2. *STD 650 Welded Steel Tanks for Oil Storage, Ninth Edition, July 1993 (incl. Addendum of December 1994 and December 1995)*

This document is a design reference for aboveground vertical, cylindrical storage tanks. API STD 650 tanks are designed to contain the vapor above the liquid at pressures approximating atmospheric pressure (not exceeding 2.5 psig) and at maximum operating temperatures usually not exceeding 200°F. API researched and collected the combined knowledge of eleven professional organizations and industry to cover material, design, fabrication, erection, and testing requirements. All aspects of tank design are covered or referenced in this document from foundation to connection to the pipeline. Essentially, this could be a sole source reference for the design and construction of new welded tanks for oil storage. Information in the standard allows the engineer or designer the opportunity to choose several different options in the design. This standard will allow for different roof types, foundations, venting, seals, and other items that make this document function as a guide for design rather than as a plan for designing one specific style of structure. Using the criteria and design principles found in this document, the engineer can plan the tank to tit the application, whether it is for a site in West Texas or a site on the North Slope of Alaska. This standard replaced API 12A (Riveted), 12B (Bolted), and 12C (Welded) which were the previous aboveground storage tank specifications published by API.

The following items are examples of specific sections of the text which we believe may be of importance to OPS. Modifications are suggested to enhance these sections.

Section 1 Introduction

1.1 General

This section defines the scope of the contents of this document. Numerous times, this section relates to the operator or purchaser in this section. For Federal Code or standard, it may be useful to indicate the reference to be the Office of Pipeline Safety or the Department of Transportation.

1.1.11

This section states that "Appendix I provides the basic recommendations for design and construction of tank foundation systems that provide leak detection and subgrade protection in the event of bottom leakage". OPS may wish to review the need for leak detection for tanks with bottom leakage problems.

Section 3 Design

3.9 Top and Intermediate Wind Girders

3.9.6 Top Wind Girder

This section contains the design criteria for the wind girder. In the first paragraph, an equation is given that defines the minimum section modulus. This equation and the criteria for design are based on 100 mph winds. This may not be adequate for the entire United States. Some areas, particularly the Gulf and the East coasts, may have sustained winds during hurricanes over 125 mph. For this section, OPS may consider possibly some geographic criteria, such as all tanks within 100 miles of the coast to use a minimum wind load of 125 mph.

3.1 Roofs

Section 3.10 defines the roof types and outlines the methods used to design the various types. In the future this section may include bnly floating, internal floating, and domes. OPS may consider deleting the section on cone roofs without internal floaters, since they are no longer allowed for environmental reasons.

Section 5 Erection

5.3 Inspection, Testing, *and* Repairs

5.3.2 Inspection of Welds

5.3.2.3 *Costs*

This item directs financial responsibility, which is usually not included in Federal Codes. This may need to be deleted.

5.5 Dimensional Tolerances

5.5.5 Foundations

Within this item is the specification for tank foundations. The criteria for ring walls appears to be too stringent. This specification calls for the ring wall to be level within 0.125 inches in any 10 feet of the circumference and within 0.50 inches over the entire ring. This specification may be too stringent and unnecessary.

Section 6 *Methods of Inspecting* Joints

6.1 Radiographic Method

6.1.2 Number and Location of Radiographs

6.1.2.4

This section mentions methods of taking radiographs of welds on the shell. Part of this section allows for the use of ‘aggregate welds for multiple tanks under construction for determining the number of welds to be inspected. This could allow a tank to be missed during inspection. OPS may wish to review this section to reflect a single tank under construction.

Section 8 Marking

8.1 Nameplates

Consideration may be given to indicate the minimum operating temperature.

Appendix C External Floating Roofs

C.3 *Design*

C.3.8 Roof Drains

This section contains design criteria for roof drains. The criteria calls for the hose to be removable without entering the tank. This, however, could be a problem with new drain hose design. The coflexit hose, due to its design, requires the tank to be drained to disconnect the systems used to support the hose. A review of design criteria for roof drains may be warranted.

C.3.10 Supporting Legs

Criteria for height of legs is left up to the operator. The minimum height allowed for an enclosed work area where employees will work may be limited by OSHA and may not fall under the purview of the operator. The minimum height for operating could be limited by the installation of internal items in the tank.

Appendix D Technical Inquiries

This appendix may need to be written to reference DOT or OPS instead of API.

Appendix G Structurally Supported Aluminum Dome Roofs

The temperature limits in this section may not be relevant under the definition of breakout tank. Temperatures greater than 200°F are considered unlikely for tanks used within a pipeline system.

Appendix I Undertank Leak Detection and Subgrade Protection

OPS may wish review the need for leak detection for tanks with bottom leakage problems

Appendix M Requirements for Tanks Operating at Elevated Temperatures

Requirements for tanks at elevated temperature for this study are not relevant. This appendix addresses problems with tanks designed for temperatures greater than 200°F and less than 500°F. These conditions should never be seen under our definition of breakout tanks.

3. *RP 651 Cathodic Protection of Abovearound Petroleum Storage Tanks. First Edition, April 1991*

This document, Recommended Practice 651, contains those practices, procedures, and engineering principles necessary to design, operate, and maintain corrosion control on tank bottoms for aboveground storage tanks. This document gives the information and criteria to design and operate systems installed or planned under multiple design criteria. Anyone owning or operating a facility would use this document as a guide for cathodic protection.

Section 3 Determination of Need for Cathodic Protection

3.1 Introduction

This section details the criteria for determining the need for cathodic protection. For Federal Code purposes, specific expectations or goals may need to be written that will either require protection or allow operation without protection.

Section 7 Installation of Cathodic Protection Systems

7.4 Corrosion Control Test Stations, Connections, and Bonds

7.4.4 Corrosion Control Test Stations, Connections. and Bonds

As noted before, wording can be a concern when using this document. Within this paragraph, the authors ask for consideration in using one of two methods. This section may need to be written to indicate the use of one of the two methods.

7.4.6 Corrosion Control Test Stations, Connections, and Bonds

This paragraph states that the operator should consider the installation of reference cells or half-cells under the tank during bottom replacement. Several operators have already begun to install them; some are even installing cells before replacing bottoms. OPS may wish to review the need for installation of reference cells or half-cells during tank bottom replacement.

4. *RP 652 Lining of Aboveground Petroleum Storage Tank Bottoms. First Edition, April 1991*

This recommended practice document, in its first edition, addresses the potential need to line the interior bottom of storage tanks. Lining of tank bottoms has been a very effective method of controlling and limiting the interior corrosion of tanks in hydrocarbon service. These guidelines can give information on determining whether corrosion is occurring, finding the location of the corrosion, and determining the optimum tank lining to correct the problem.

This document in some areas is only general in content. An example is the topic of Corrosion Mechanisms. Corrosion is covered in much greater detail in other API Recommended Practices.

Section 3 Determination of the Need for Tank Bottom Lining

3.2 Linings for Corrosion Prevention

This section sets the minimum standards for requiring the installation of a lining. As in many of these API documents, the emphasis is on the responsibility of the operator. OPS may wish to review the requirements to install a lining if conditions warrant it.

3.5 Environmental Considerations

This section appears ambiguous. There are no guidelines or recommendations. If environmental issues are addressed, they need to be more specific.

5. *STD 653 Tank Inspection. Repair, Alteration, and Reconstruction. Second Edition, December 1995*

This standard covers the operation and maintenance of all steel aboveground tanks built under API STD 620 and 650 and its predecessors, API 12A, 12B, and 12C. Before this standard was first released in 1991, the industry was left with two basic options: develop their own internal company guidelines or go without. Inspection, repair, and alteration sometimes did not occur until a problem arose, such as a bottom failure or leak. In today's environment, these options are no longer recommended. To optimize their asset, the operator needs to be proactive. This standard gives the operators basic guidelines to operate their tanks. The primary emphasis is on inspection but other criteria are covered. Special consideration has been given to selecting inspection techniques and scheduling. The weakness of this standard appears to be that it does not specify schedules and tests.

Section 2 Suitability for Service

2.3 Tank Shell Evaluation

2.3.2 Actual Thickness Determination

This section covers the method of calculating the controlling thickness of the shell wall. It appears to be vague, in that it does not state the method of data collection. Will it be taken when the tank is out of service, from the inside, or from ultrasonic testing? It also appears not to indicate how many tests, how many per ring course, and what pattern of samples to take during the tests.

2.4 Tank Bottom Evaluation

2.4.1 General

This section mentions that there should be a schedule for testing and inspection of foundation settlement, but appears not to state the schedule or a method of determining when to inspect. It mentions a reference to a later section, but it would be useful to state the time interval of the inspection in this section.

2.4.5 Bottom Leak Detection

API asks the operators to consider adding leak detection for tanks when replacing tank bottoms. OPS may wish to review the need for addition of leak detection during replacement of tank bottoms, if warranted.

2.4.6 Bottom Plate Thickness Measurements

Bottom plate thickness is very important for the determination of corrosion rate and life of the tank bottom. API recommends that the operator determine the corrosion rate in the bottom plate. It does not specifically *give* a frequency, number, and pattern for corrosion rate measurements. Without some guidance, it appears that the measurements obtained from an inadequate number of tests may not reflect the average corrosion rate.

Section 4 Inspection

4.2 Inspection Frequency Considerations

4.2.2

For inspection, scheduling needs to be considered. This section gives special emphasis on this topic. The guidelines for tank inspection under this paragraph are vague, stating that age, location, history, and corrosion rate determine the inspection frequency. Inspection scheduling under these guidelines would be left to the operator without a clear method of determining the schedule. OPS may wish to consider a possible schedule such as the following:

1. Cursory or informal routine external inspection monthly,
2. Formal external inspection every 5 years, and
3. Internal inspection at least every 20 years; an inspection within 10 years if tank history is incomplete or if the tank is taken out of service for internal maintenance or relining.

4.3 External Inspection

4.3.2 Scheduled Inspections

4.3.2.3

For inspection of cathodic protection. specific guidelines would appear to be necessary. Stating that the operator should follow API RP 651. without giving some guidelines as to the time interval for inspection, may not be adequate.

4.3.3 Inservice Ultrasonic Thickness Measurements of the Shell

This section states that ultrasonic measurements can be useful to the operators. The last sentence states that the extent and number of measurements will be left up to the operator. As standard tests are desirable. it may be useful to indicate that the number of measurements would need a minimum number of tests per course and the location on the shell for the tests. Additional industry input may be used to determine if additional measurements are necessary and define the method of determining the number of additional measurements.

6. *STD 2000 Venting Atmospheric and Low-Pressure Storage Tanks: Nonrefrigerated and Refrigerated, Fourth Edition, September 1992*

All of the tanks built under API STD 620 and 650 and their predecessors require some type of venting. Due to the volatility of the product, the ambient temperature, and the condition of the product at arrival, some vapor release may occur. Since these are either static or low pressure tanks, some consideration must be taken to venting vapor from the tanks. This standard covers both conventional and emergency venting of tanks. The design standards STD 620 and 650 use STD 2000 as the method or optimum criteria for reviewing actual conditions on tank design as well as the guide to determining the conditions present on as-built tanks. The guidelines help the engineer design his system to meet the criteria for his facility. Our recommendation is that a section needs to be added for the venting of geodesic domes.

7. *RP 2003 Protection Against Ignitions Arising Out of Static, Lightning, and Strav Currents. Fifth Edition, December 1991*

This Recommended Practice presents the current technology in the field of static electricity, lightning, and stray currents applicable to the prevention of hydrocarbon ignition. Several effective basic steps that may be taken to prevent static ignition are discussed. The recommendations are based on research and experience in the petroleum industry. Their implementation should lead to improved safety practices.

8. *RP 2015 Safe Entry and Cleaning of Petroleum Storage Tanks, Fifth Edition, Mav 1994*

Before maintenance can occur on the interior of the tank, specific guidelines must be followed for the safety of personnel entering the tank. This topic has been covered extensively by OSHA and EPA in the past. This is a compilation of the items that must be covered before the tank can be repaired or altered. A lot of this material is found in API STD 653 for decommissioning tanks for repair. This is an excellent guide for the operator, but for use in Federal Code the entry guidelines may have already been covered by other agencies.

9. *RP 2350 Overfill Protection for Petroleum Storage Tanks in Petroleum Facilities, Second Edition, January 1996*

Overfill is the cause for loss of liquids in the majority of aboveground tanks. This guide gives insight into methods used by industry to prevent overfill. This can prevent “re-inventing the wheel” for engineers who design the control portion of their facility. Without some type of protection, personnel would be required to manually monitor tank levels at each tank and signal the control room or operate the pumps and valves continuously.

10. STD 2610 Design, Construction. Operation. Maintenance, and Inspection of Terminal and Tank Facilities, First Edition. July 1994

For guidance in design or operation, it is often desirable to have one book or manual that covers all aspects of the project. This document is an attempt to achieve this goal. The document attempts to cover all of the items that are necessary to design, construct, operate, maintain, and inspect terminal and tank facilities. It gives a great overview of many sections of the other API Standards and Recommended Practices, it does not however, give all of the details necessary to complete all of its goals. Throughout this document, it refers back to STD 650, STD 653, and other appropriate references. This is a good survey or overview document because it tells the engineer which reference he or she will need to complete the design or facility modification.

, 11. *ANSI/NFPA-30 Flammable and Combustible Liauids Code, I996*

This document was not listed for review in this project. However, STD 2610 referenced this document several times for tank farm layout and berm design. From review and discussion, ANSI/NFPA-30 is the document used by industry for facility layout design. It was written to limit and contain damage to facilities from fire. The design criteria for tank spacing and diking, both “remote impounding” and “impounding around tanks by diking” are discussed. OPS may wish to review the allowable number of tanks, size of berm, and location.

B. Impact of Standards and Recommended Practices on Tank Safety

The objective of this research was to improve the safety of breakout tank facilities. Safety of these facilities can be classified into several categories: safety of personnel working onsite, safety of the environment, safety of private property, and safety of public property.

All operators visited have made efforts to increase the safety of their facilities and to protect personnel. The reasons for this are humanitarian, environmental, and economic. The humanitarian reason needs no explanation, but the environmental and economic reasons need to be highlighted. In the event of an accident, product may be lost, private or public property may be damaged or destroyed, a pipeline storage facility could be damaged or destroyed, and the ability of the facility to provide products to end users could be impaired. Waterways and reservoirs could be polluted, and fmally there would be a financial loss to the terminal operator.

Protecting the environment is a relatively new aspect to operational considerations. The majority of tanks were built before 1950. This was long before major concern by the public for environmental issues. Not many years ago, oil that was spilled or not transportable was used for surfacing lease roads, was spread over the site to prevent weed growth, or to consolidate the soil and help the water run off after storms. This use of oil has stopped.

Studies have been carried out by OPS and API to evaluate the impact of implementation of the API standards and regulations to monitor environmental accidents. OPS completed a study in 1988 titled *Project 87-3 Leak Defection from "Breakout Tank" Bottoms* which discussed the need for leak detection and inspection of breakout tanks. This report presents an analysis of data of 2,139 DOT liquid accident reports collected from 1977-1986. Of the 2139 accidents, only 136 involved breakout tanks. Table 3 shows *a* breakdown of these accidents, The 136 breakout tank accidents represents 1% of the breakout tank total of ~9,197 estimated by API in 1989, or 0.1% of the total on an annual basis.

Based on OPS's reported accident data for breakout tanks for the period. 1987-1996, 152 accidents were recorded. The categories for these accidents are different from those in the 1987 OPS report for the period, 1977-1986. Moreover, a brief review of these accidents indicate that many may not be reportable accidents, in that they involve spills less than OPS's minimum volume for reportable accident of 50 BBLS. In addition, the minimum property damage value for reportable accidents have changed over time: $1,000 (April 1, 1970 - July 26, 1981), $5,000 (July 27, 1981 - June ~~26~~ 27, 1994), and $50,000 (June 28, 1994 - present). Consequently, these accidents appear not to be directly comparable with those in the period, 1977-1986.

A better analysis of the impact of implementation of the API standards is in a second survey conducted by API in 1994. This report was titled *A Survey of API Members' Aboveground* Storage *Tank Facilities, July* 1994. This survey was to determine if groundwater contamination had occurred, and if so, the cause of contamination, remedial method used, and whether improvement in operation consideration had any effect on the cause of contamination.

The API report dealt with the three industry sectors i.e. relining, marketing, and transportation. The survey addressed only the tank farm portion of each sector. In the transportation sector, this involved 140 large and small tank farms. The report stated that contamination onsite due to operation, design, construction, and maintenance had dropped from 3.6% of the facilities to 0.8%, comparing the previous history to the last live years. Since this report was on facilities, comparison with the 1988 OPS report or OPS's 1987-1996 accident reports is not possible. Improved equipment was credited for reducing accidental releases by 75% of those who responded to the survey. The primary practices mentioned by industry personnel, that affected operations, were API STD 653 and RP 65 1. The facilities handle various liquid types: 63% were crude oil, 33% refined product, and 4% mixed products. Since adoption of RP 2350 and STD 653, accidents involving liquids lost has been drastically reduced. This report stated that 60% of the transportation facilities were using API STD 653. From our site visits, the consensus was that 100% of the operators were using this standard and were conducting tank inspections. Most have used the API Standards and Recommended Practices, as well as the "checklists" found in API STD 653 Appendix C, as a minimum guide and developed their (site specific) design. construction.

Table 3. Breakdown of 136 Accidents Reported to DOT as Liquid Accidents for Breakout Tanks (1977-1986)

Type of Failure	Number of Accidents	Percentage of Total Failures
Corrosion	16	12
Operator Error	50	37
Outside Forces	2	1
Malfunction of Control/Relief Valve	1	1
Equipment Malfunction	21	15
Roof Drain Leak	20	15
Lightning	5	4
Valve Leaks	5	4
Seal Leak	5	4
Tank Rupture	4	3
Tank Cleaning	3	2
Gauge Nipple	2	1
Hole in Tank	2	1

operating, maintenance, and inspection standards and practices, some of which surpass the recommendations outlined by API.

V. SUMMARY AND CONCLUSIONS

The objective of Task 1 was to develop recommendations for the adoption of industry standards for the design, construction, operation, and maintenance of aboveground pipeline breakout tanks and secondary containment structures. To attain this objective, the following sub-tasks were completed.

a. An analysis of existing aboveground breakout tank standards was conducted. This analysis covered API Standards and Recommended Practices, STD 620, 650, 653, 2000, 2015, 2610; RP 651, 652, 2003, 2350; and ANSI/NFPA-30.

b. Tank facilities were visited at 16 sites in six states. The sites had a total of 411 aboveground breakout tanks with approximately 47 million barrels of storage. These tanks were geographically spread out across the lower 48 states. These sites were in the following six states: Texas, Louisiana, Wisconsin, California, New Jersey, and Oklahoma. The objective of the site visits was to discuss with the field personnel in charge of each site, the standards they used to design, construct, operate, and maintain their breakout tanks. This included discussion of the standards used to construct, operate, and maintain the site.

c. Based on analysis of current API Standards and Recommended Practices and from the site visits, recommendations were developed for adoption into 49CFR Part 195 for aboveground breakout tanks.

The majority of the breakout tanks visited were built before 1950. Of these, all of the tanks built before 1936 were riveted. These riveted tanks were built with API 12A as the standard because it was valid from 1928 to 1941 for riveted construction. A large number of tanks in Oklahoma were built before 1928. These tanks appear to meet the criteria used later in API 12A. All of the welded tanks built before 1961 used API 12C as their standard. The tanks built after 1961 used API STD 650 as the standard. On the whole. the tanks visited were in excellent condition.

Based on the 1989 tank survey prepared for API, there are an estimated 9,197 breakout tanks associated with the transportation in the U.S. A report prepared by OPS in 1988 indicated that in the period, 1977-1986, there were 136 DOT leak accidents that relate to breakout tanks. This figure represents, on an annual basis, only 0.1% of the breakout tanks. A 1994 report by API for EPA indicates that the rate of accidents has decreased from 3.6% to 0.8% of the facilities when comparing the past history to the last five years. They attribute this reduction principally to the implementation of API Standards and Recommended Practices, specifically, STD 653, RP 65 1, and RP 652. However, we also see the safety benefits resulting from the adoption of API STD 620, 650, 2000, 2015, and 2610; and RP 2003, and 2350. Consequently, it is recommended that OPS adopt these 10 API publications and ANSI/NFPA 30 by incorporation into the Pipeline Safety Regulations in 49CFR Part 195.

Based on our review of the API publications, together with site observations and discussions with tank operators, some preliminary suggestions have been made to further improve certain aspects of these publications. The main items - suggested for possible review by OPS in future - are in respect of uniformity in: tank shell ultrasonic inspection; tank bottom MFE and ultrasonic inspection; tank grounding; and monitoring and recording of cathodic protection under tank bottoms.